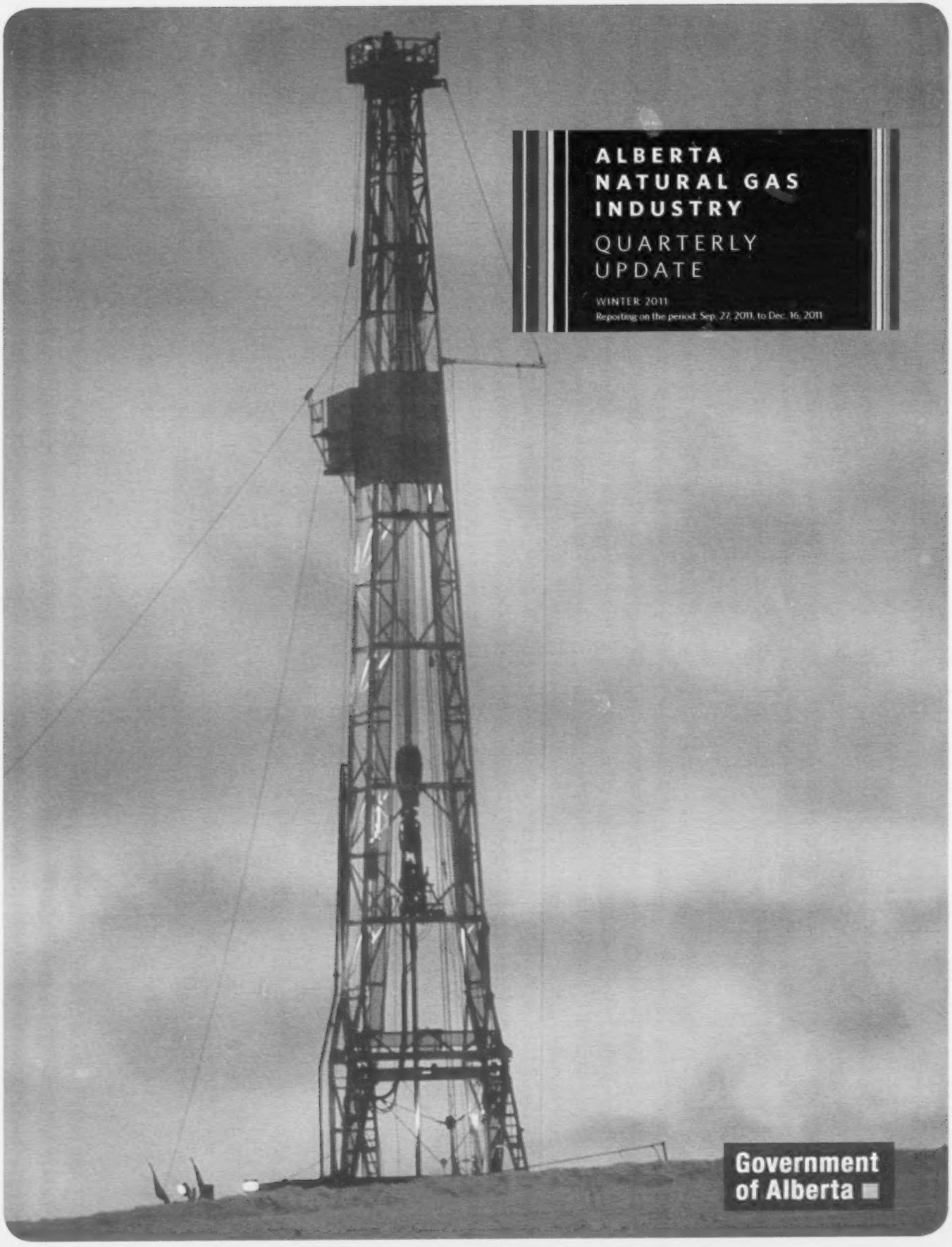
ALBERTA
NATURAL GAS
INDUSTRY
QUARTERLY
UPDATE
WINTER 2011
Reporting on the period: Sep. 27, 2011, to Dec. 16, 2011
Government
of Alberta

All about natural gas

Background of an important western Canadian resource

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Natural gas has been a key part of the Canadian economy and energy mix for many decades, and the Western Canadian Sedimentary Basin (WCSB)—and more specifically Alberta—has led the way.

Canada is the third-largest natural gas producer in the world, with about 80 per cent of the country's gas being produced in Alberta. In 2010, Alberta produced 4.1 trillion cubic feet of marketable natural gas, including production of approximately 3.8 trillion cubic feet from conventional sources and 0.3 trillion cubic feet from coalbed methane (CBM).

According to provincial figures, at the end of 2010, remaining established reserves of conventional natural gas stood at 36.4 trillion cubic feet while remaining established CBM gas reserves stood at 2.4 trillion cubic feet. Reserve additions as a result of new drilling replaced 46 per cent of 2010 gas production. The province estimates the remaining ultimate potential of marketable conventional natural gas at 74 trillion cubic feet.

Although conventional natural gas remains a very important part of western Canadian production and Canada's natural gas supply, a new era is upon us. The industry has now advanced new technology, such as horizontal drilling and multistage fracturing, to the point that allows for development of natural gas from a new source—unconventional natural gas resources. Aside from CBM, Alberta's unconventional natural gas resources include tight gas (natural gas trapped in low-permeability sedimentary rocks, such as sandstone or limestone) and shale gas (trapped in shale rock).

The Canadian Society for Unconventional Resources has estimated that the recoverable, marketable portion of Canada's unconventional resource is from 376 trillion cubic feet to 947 trillion cubic feet. Remaining gas in place in conventional reservoirs is estimated to be 692 trillion cubic feet, and 357 trillion cubic feet of that resource is expected to be recoverable and marketable, with a total marketable resource from both conventional and unconventional resources of 733 trillion cubic feet to 1,304 trillion cubic feet.

Most of the unconventional natural gas resources occur within the WCSB, a thick package of oil- and gas-prone rocks that cover much of Alberta, Saskatchewan, parts of British Columbia, southwestern Manitoba and northwards into the Northwest Territories.

But there's more to the province's natural gas industry than drilling wells and producing resource, as to make it accessible to Albertans and for export to other markets, a vast infrastructure network is required. Approximately 97 per cent of all oil and gas products move by pipelines in Canada, representing more than three million barrels of crude oil and over 15 billion cubic feet flowing every day through Canada's 580,000 kilometres of pipelines. And this vital transportation network is centred largely in Alberta.

Approximately 70 per cent of natural gas produced in Alberta is exported to other provinces and the United States. Alberta is the largest supplier of natural gas to the United States and currently delivers all of its exports (excluding Canadian provinces) to its southern neighbours, the majority of which goes to the Midwest. Disposition of Alberta's natural gas production in 2010 was approximately:

- 45 per cent to the United States;
- 29 per cent within Alberta; and
- 26 per cent to the rest of Canada.

Alberta's natural gas pipelines deliver natural gas across the provincial border to the Canadian Mainline, B.C. System, the Foothills System and others, connecting provincial energy production to locations as far away as the ports of Metro Vancouver and Prince Rupert and various hubs in the United States.

There are over 392,000 kilometres of energy-related pipelines (including oil and natural gas) as well as extensive storage facilities in the province. This infrastructure is an essential lifeline linking Alberta's natural gas resource to national and U.S. markets.

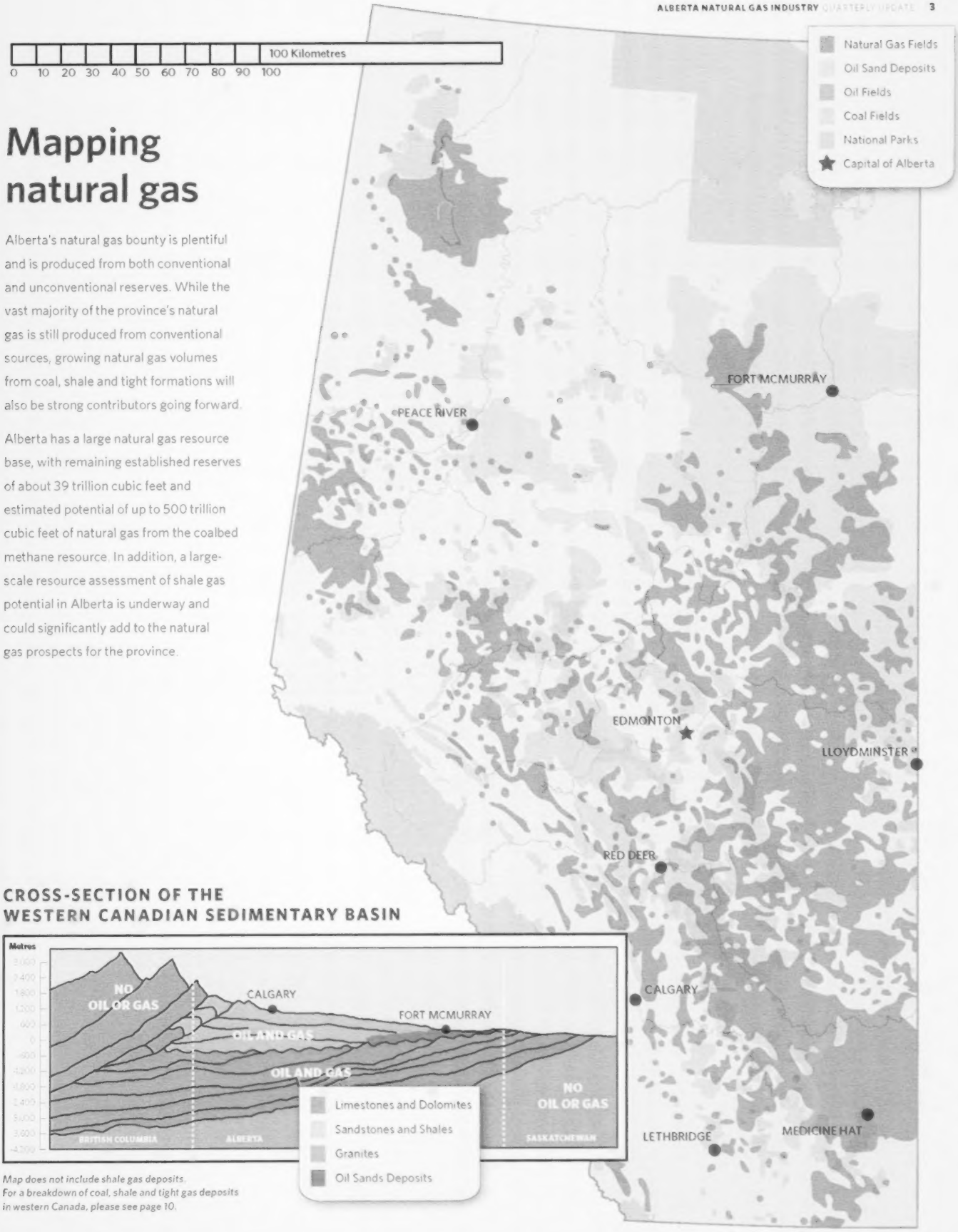
On the environmental front, Alberta has received international attention for its successes in natural gas flaring and venting reductions. Since 1996, solution gas flaring in Alberta has been reduced by 76 per cent. In 2007, the upstream oil and gas industry conserved nearly 96 per cent of all solution gas produced in Alberta for use and sale, rather than flaring and venting it.

By reducing the amount of natural gas that is wasted, Alberta helps ensure that it makes the most effective use of its natural gas resources, and continues the province's record as one of the global leaders in conservation and flaring reductions. ■

Mapping natural gas

Alberta's natural gas bounty is plentiful and is produced from both conventional and unconventional reserves. While the vast majority of the province's natural gas is still produced from conventional sources, growing natural gas volumes from coal, shale and tight formations will also be strong contributors going forward.

Alberta has a large natural gas resource base, with remaining established reserves of about 39 trillion cubic feet and estimated potential of up to 500 trillion cubic feet of natural gas from the coalbed methane resource. In addition, a large-scale resource assessment of shale gas potential in Alberta is underway and could significantly add to the natural gas prospects for the province.



CROSS-SECTION OF THE WESTERN CANADIAN SEDIMENTARY BASIN

Map does not include shale gas deposits.
For a breakdown of coal, shale and tight gas deposits in western Canada, please see page 10.

Government update

NEW CABINET TEAM FOCUSED ON ALBERTANS' PRIORITIES

In October, Premier Alison Redford named a new cabinet. "This cabinet reflects what change looks like. It's a team that's committed to listening to Albertans and getting to work right away on bringing the change Albertans want and expect," Redford said.

The new cabinet is committed to serve Albertans in a renewed government structure. The newly created Ministry of Human Services brings together programming for children and families in need. Aboriginal relations and immigration have been moved to Intergovernmental, International and Aboriginal Relations to coordinate federal and aboriginal portfolios better. The function of economic development for the province was moved to Treasury Board and Enterprise. The Ministry of Environment and Water emphasizes the importance of protecting one of Alberta's greatest resources.

For the government news release announcing the cabinet structure with the list of the new ministers and committee members, please visit http://alberta.ca/NewsFrame.cfm?ReleaseID=/acn/201110/31365F8B1C3DE-99E3-570E-0FA956FC8C5B45FF.html

ALBERTA GOVERNMENT IN THE PROCESS OF DEVELOPING A NATURAL GAS STRATEGY

The Department of Energy of the Alberta Government is developing a natural gas strategy to address the near- and long-term competitiveness of Alberta's natural gas supply as well as future market opportunities.

The natural gas strategy will examine:

- natural gas supply outlook (conventional and unconventional);
- forecasted demand for natural gas (residential, commercial and industrial);
- use of pipelines;
- exporting opportunities (Kitimat liquid natural gas);
- natural gas as a transport fuel; and
- use in electrical generation.

The objectives of the strategy are to ensure long-term competitiveness of Alberta's natural gas businesses, maintain near-term activity and investment as well as support value-added natural gas activities.

The strategy will also focus on use of natural gas in bitumen and synthetic crude oil production as well as petrochemical production.

NEB GRANTS 20-YEAR EXPORT LICENCE TO KM LNG

In October, the National Energy Board (NEB) approved an application by KM LNG Operating General Partnership (KM LNG) for a licence to export liquefied natural gas (LNG) from Kitimat, B.C., to markets in the Asia Pacific region.

The export licence authorizes KM LNG to export 200 million tonnes of LNG (equivalent to approximately 265 million 10^3m^3, or 9,360 billion cubic feet, of natural gas) over a 20-year period. The maximum annual quantity allowed for export will be 10 million tonnes of LNG (equivalent to approximately 13 million 10^3m^3, or 468 billion cubic feet, of natural gas).

The supply of gas will be sourced from producers located in the Western Canadian Sedimentary Basin. Once the natural gas has reached Kitimat by way of the Pacific Trail Pipeline, the gas would then be liquefied at a terminal to be built in Bish Cove, near the Port of Kitimat. The construction and operation of the pipeline and the terminal will require provincial regulatory decisions.

This is the first application for an LNG export licence that the board has considered since the deregulation of the natural gas market in 1985.

The board acknowledges the potential economic benefits associated with KM LNG's project. These benefits include employment opportunities due to the development of the LNG terminal and the Pacific Trail pipeline.

PROCESS TO HEAR THE TRANSCANADA RESTRUCTURING TOLLING APPLICATION IS UNDERWAY

The National Energy Board (NEB) issued in September a hearing order starting the process to hear the application jointly filed by TransCanada PipeLines Limited, NOVA Gas Transmission Ltd. and Foothills Pipe Lines Ltd. (TransCanada).

In its application, TransCanada is asking the Board to consider restructured pipeline services and tolling across its pipeline network, which includes the Mainline, the Alberta System and the Foothills System. The Board is also being asked to approve final Mainline tolls for 2012 and 2013.

The NEB has already launched a process inviting interested persons to provide procedural suggestions that will allow for a fair and efficient process. A Pre-Hearing Planning Conference took place Oct. 12, 2011. Following the conference, the schedule for public hearing was released. The hearing will be held in Calgary (June 4-29, 2012, and as needed Sept. 10-Oct. 5, 2012), Toronto (July 9-20, 2012) and Montreal (Aug. 20-31, 2012).

For additional information about this hearing or the procedures governing the hearing, please call the NEB's toll-free number at 1-800-899-1265 and specify that the call is about the TransCanada application related to 2012 and 2013 Mainline tolls (reference number RH-003-2011).

Please visit the NEB website for general information about the hearing process and how you can participate effectively. To access the information, go to www.neb-one.gc.ca.

ERCB ANNOUNCES CHANGES TO WELL-SPACING FRAMEWORK

The Energy Resources Conservation Board (ERCB) issued Bulletin 2011-29, which advises of regulation amendments to change its well-spacing framework for conventional and unconventional oil and gas reservoirs.

The changes allow for enhanced conservation of Alberta's oil and gas resources by enabling companies to optimize resource recovery in a safe, efficient and responsible manner that maximizes the benefit of the resources for all Albertans.

Well spacing relates primarily to the subsurface aspects of reservoir development and does not impact the rights of landowners with respect to surface development. ERCB requirements for development of all surface facilities, such as wells and pipelines, which include public notification requirements and allow landowners to participate in ERCB processes, remain unchanged.

Effective immediately, the ERCB has made four changes to its well-spacing framework:

- Subsurface well-density controls for coalbed methane and shale gas have been removed across Alberta and in certain gas zones in southeastern Alberta.
- Baseline well densities have been increased from one well to two wells per pool per standard drilling spacing unit province-wide for conventional gas reservoirs.
- Centralized target areas for drilling spacing units will be standard throughout Alberta, with the exception of a specific area in southeastern Alberta where corner target areas will be standard for gas reservoirs only.
- Regulation amendments have been implemented that decrease the complexity of the current spacing framework.

NEB RELEASES THE REPORT *CANADA'S ENERGY FUTURE: ENERGY SUPPLY AND DEMAND PROJECTS TO 2035*

In November, the National Energy Board (NEB) released a report titled *Canada's Energy Future: Energy Supply and Demand Projects to 2035*. The report examines energy trends in Canada and provides a view of energy supply to 2035.

To gather information for the report, the NEB held cross-Canada consultations last spring to seek the views of Canadian energy experts and other interested stakeholders, and then conducted its own extensive quantitative analysis.

Among key findings in the report, based on a moderate "mostly likely" view of future energy prices and economic growth, are:

- Although energy from fossil fuels will remain the dominant source of supply, emerging fuels and technologies will gain market share as policies and programs promote growth in these areas. The share of biofuels in transportation-sector energy consumption will triple over the projection period, from 1.1 per cent to 3.3 per cent in 2035, while the share of renewable-based electricity generation will increase from 62 per cent to 67 per cent in 2035.
- Energy supply will grow to record levels fuelled by the emergence of unconventional production such as oil sands, shale gas and tight gas, and—in the area of power production—construction of new generating capacity to meet steadily increasing demand.
- Total end-use energy demand growth will slow to 1.3 per cent during the projection period, down from 1.4 per cent from 1990 to 2008. Factors reducing demand include slowing population growth, higher energy prices, lower economic growth, and enhanced efficiency and conservation programs. While demand will slow considerably in the residential, commercial and transportation sectors, it will be partially offset by industrial-sector demand growth. The industrial sector accounted for almost half of Canadian energy demand in 2010.
- Net crude oil available for export will more than triple by 2035, and net electricity available for export will double in that period. The amount of natural gas available for export is expected to gradually decline until 2020 due to increased Canadian demand for natural gas. After 2020, production growth and demand growth will be about the same.

The document also outlines four additional cases based on high and low energy prices, and fast and slow economic growth.

To view the report and detailed data used to develop it, visit the Energy Reports section on the main page of the NEB website at www.neb-one.gc.ca. ■

What's new in natural gas

ALBERTA SETS ALL-TIME LAND SALE RECORD

The Alberta government set an all-time calendar year record for land sale bonus revenue on November 30 after an auction of $67.01 million pushed the 2011 total to $3.439 billion, eclipsing the previous watermark of $3.433 billion.

The 2006 record—which seemed unbeatable just a few short years ago—was set due to heavy spending for oil sands acreage. However, the new record was reached because horizontal drilling and multistage hydraulic fracturing are making it possible to develop previously uneconomic formations. The November 30 sale featured 143,765 hectares exchanging hands at an average of $466.13.

Year-to-date to November 30, the provincial government had sold 4.4 million hectares at an average of $781.06. The final sale of 2011 was scheduled for December 14, which was after editorial deadline.

Gary Leach, executive director of the Small Explorers and Producers Association of Canada, said that prior to this year, most industry observers would likely have bet that the 2006 Alberta record was the permanent high watermark, particularly since the old record was boosted by an oil sands land rush.

"To actually set a new record at $3.439 billion is very impressive, and [it is] worth considering how and why it happened," he said.

A great deal of this spending rests on industry's belief that there is a large resource potential, especially liquids-rich natural gas and crude oil from tight formations and shale, that can now be profitably developed through advances in horizontal well completion technology, particularly from the fracture stimulation component, Leach noted.

"This has spurred a significant [amount of] spending to acquire positions in plays such as the Duvernay," he said. "I also think the Alberta royalty changes put in place in the first half of 2010 have contributed to the economics for these types of plays."

In terms of land spending being a predictor of future activity, Leach said investment in land on this scale is a big commitment by the industry to further capital investment in Alberta.

"If crude oil prices remain at attractive levels, which also supports the economics of liquids-rich gas, then Alberta's upstream sector should see a robust level of activity, which brings its own challenges in terms of labour shortages and upward pressure on drilling and service costs," he added.

Brad Hayes, president of Petrel Robertson Consulting Ltd., said that the land sale results in Alberta in 2011 are clearly the result of new horizontal drilling and multi-frac completion technology, allowing companies a legitimate chance to produce various shale and tight reservoir plays economically.

Hayes said the big drivers for the record expenditures were plays like the Duvernay shale, Swan Hills tight carbonates, Montney, Alberta Exshaw/Bakken shale and tight oil, Nordegg shale, the Second White Specks "and probably some others that haven't hit the news yet.

"I am surprised that this record occurred. Even had we foreseen in 2006 that shale and tight plays would take off as they have, I wouldn't have thought that companies would move so quickly and with such big dollars," he said. "We will most likely see a number of very expensive wells drilled to test these plays."

PRODUCERS CONTINUE TO INVEST MORE IN 2011

A focus on oil sands projects, crude oil development drilling and liquids-rich natural gas plays has led to several producers active in Alberta and other areas of western Canada to hike their capital spending budgets for 2011—in some cases multiple times.

In outlining their spending plans in late 2010 or earlier in 2011, producers initially set a budget of $51.27 billion for 2011 spending.

As of the end of September, that spending figure had ballooned by $4.16 billion to a total of $55.43 billion expected for the year.

The companies with the largest increases in budgets, in absolute dollar terms, are Canadian Natural Resources Limited (up $1.26 billion), Apache Canada Ltd. (up $380 million), Crescent Point Energy Corp. (an increase of $250 million), Cenovus Energy Inc. (up $200 million) and Devon Canada Corporation (also up $200 million).

A recent surge in equity financings has also led to companies hiking their spending plans in 2011. In September, companies such as Tourmaline Oil Corp. and Celtic Exploration Ltd. both entered bought-deal equity financings to help boost their spending plans for Deep Basin activities.

At the end of September, 53 producers have reported plans to increase their capital spending budgets from initial plans, as oil prices remain strong despite some recent volatility on world crude markets.

Only three companies announced decreases in capital spending: TriOil Resources Ltd. (down $12.50 million), NuVista Energy Ltd. (down $10 million) and Hawk Exploration Ltd. (down $500,000).

ENCANA NATURAL GAS CNG STATION OPENS IN STRATHMORE

An Encana Corporation subsidiary's first compressed natural gas (CNG) station in Alberta has opened in Strathmore, Alta.

Initially, the Encana Natural Gas Inc. station, located about 40 kilometres east of Calgary, will fuel only Encana's growing fleet of natural gas-powered vehicles. Beginning next year, the company expects to offer the Strathmore station's fuelling services to other corporate fleets in the area and to the public at a later date.

Encana currently has 39 trucks converted to run on natural gas in the company's Clearwater business unit, which encompasses the Strathmore area. Overall, the company has 128 vehicles running on natural gas out of a total North American fleet of approximately 1,400 vehicles, along with 15 natural gas-powered drilling rigs, and it is continuing to further expand its conversion program.

The opening of the Strathmore facility follows the opening this past summer of Encana Natural Gas CNG stations in Fort Lupton, Colo., and Sierra, B.C. The company also has operational CNG stations in Parachute, Colo., and Red River Parish, La., which opened to its first public customer in March 2011.

Encana says that the Strathmore CNG station demonstrates its ongoing commitment to building the necessary infrastructure to support a transportation future driven by natural gas.

"Encana is leading by example as we convert our own vehicle fleets to natural gas and help build the necessary infrastructure to support its expanded use as an alternative fuel to gasoline or diesel," Randy Eresman, president and chief executive officer, said.

"Operating a fleet of vehicles on natural gas is both an economic and environmental advantage for our business, and we are inviting other business operators and consumers to join us in capturing the benefits of this clean, abundant and more affordable fuel," he said.

"We believe that natural gas as a transportation fuel has huge potential to improve the bottom line of its users. Our vast North American supply of natural gas truly represents a domestic energy solution and a way to further strengthen the economies of both Canada and the United States," Eresman added.

Natural gas-powered cars and trucks are fuelled with CNG or liquefied natural gas (LNG) and operate similarly to gasoline-powered vehicles. There are currently more than 960 natural gas vehicle fuelling stations in the United States fuelling about 110,000 natural gas vehicles. Canada has a network of approximately 80 public fuelling stations in five provinces.

Infrastructure such as the Strathmore CNG station represents another building block in the growing natural gas highway network as an increasing number of commercial and municipal fleets in North America convert to natural gas, said Eric Marsh, executive vice-president, natural gas economy and senior vice-president, USA Division.

Natural gas vehicles also have become one of the fastest-growing sectors in the alternative vehicle market, with a wide range of passenger models from small compact cars to trucks, he noted.

"This new CNG station in Strathmore...represents far more than a fuelling facility—it is a milestone along a road to a cleaner energy future and greener economy," said Marsh.

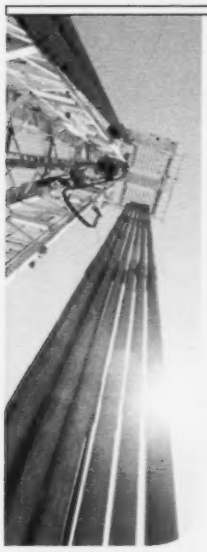
NEXT APPLICATION FILED BY NGTL

NOVA Gas Transmission Ltd. (NGTL) has filed an application seeking National Energy Board approval for a new natural gas liquids (NGL) extraction model that would enable producers to realize direct value for the NGL in the gas they deliver to the Integrated Alberta System.

The integrated system, which went into effect October 1, consists of the pipeline facilities of the NGTL Alberta system and ATCO Pipelines, which operate as a commercially integrated system using the NGTL tariff, services and rate design for all customers.

NGTL is seeking board approval for tariff amendments that would enable it to implement the NGL EXTraction (NEXT) model in the administration of NGL extraction on the integrated system. Under the model, receipt customers would be allocated NGL extraction rights (ER) based on the proportionate value of NGL in the gas they deliver to the Alberta integrated system. The extraction rights could be used to direct the flow of gas to the inlet of the 14 extraction (straddle) plants in Alberta or could be transferred between customers.

In its application, NGTL says the public interest will be served by NEB approval of the inclusion of the NEXT model in the NGTL tariff and by its implementation. "NEXT will address inequities inherent in the current convention and can be expected to increase utilization of Integrated Alberta System facilities and lower unit transportation costs through the attraction of new gas supplies with high levels of NGL to the system," says NGTL. ➤



In addition, NEXT "will improve the competitiveness of the integrated system and the Western Canadian Sedimentary Basin [WCSB] and will provide an economic alternative to field extraction of NGL, which could reduce investment in redundant field extraction facilities and improve utilization of existing extraction plants," it says.

Under the current convention, when gas is received on the Alberta system it is commingled with gas from other receipt points to form a common stream. Gas is received and delivered on an energy basis, irrespective of the composition of the gas at individual receipt points.

"Extraction rights" are allocated to customers based on their proportionate share of deliveries to certain delivery points downstream of an extraction location. Those rights enable a customer to instruct NGTL to direct a portion of the common stream at an extraction location to the inlet of a particular extraction plant or plants (banding) or to direct a portion of the common stream to bypass all of the extraction plants at that location (banding).

Customers allocating ER may sell or transfer their ER to other customers (pooling).

In its application, NGTL says that the approval and implementation of NEXT is important to the competitiveness of the Integrated Alberta System and the WCSB as a whole. "Treatment of ER and the inequities under the current convention have encumbered producers's ability to capture the value of NGL delivered to the Alberta system and blurred the NGL market signals, thereby impacting the competitiveness of the WCSB," it says.

FIRSTENERGY FORECASTS GAS PRICE REBOUND FOR 2012

FirstEnergy Capital Corp. expects AECO natural gas prices to average $4.54 per thousand cubic foot next year, up from an estimated average 2011 price of $3.84.

In releasing its price outlook October 4, the investment dealer said the AECO price averaged $3.79 a thousand cubic foot in the first quarter of this year, $3.89 in the second quarter and $3.67 in the third quarter, and it's forecasting $4 for the fourth quarter.

FirstEnergy's AECO price forecast of $4.54 for next year is down slightly from its previous 2012 forecast of $4.63 a thousand cubic foot.

The outlook for next year is more bullish than the AJM Deloitte forecast released a few days earlier, which foresees an average "real" AECO price of about $4.10 a thousand cubic foot.

FirstEnergy expects AECO prices to edge up to an average of $4.61 a thousand cubic foot in 2013 and $4.83 in 2014.

In a commentary released with the AJM forecast, Ralph Glass, AJM's director of energy valuation and operations, wrote that "continued concerns on a stagnant U.S. economy with limited growth potential" is "weighing down the need for added natural gas volumes."

FirstEnergy is forecasting an average NYMEX gas price of US$5.15 per million British thermal units in 2012, down from the firm's previous forecast of US$5.25. (AJM Deloitte expects an average 2012 NYMEX gas price of about US$4.50.)

In a presentation, Martin King, FirstEnergy's vice-president of institutional research, acknowledged that the firm's prediction of a price rebound in 2012 goes against the majority view.

"I know we're sounding very contrarian here against the rest of the street in terms of a supply outlook," King said.

'VERY STRONG INTEREST' FOR KITIMAT LNG OFF-TAKE

The three-pronged Kitimat LNG partnership is still looking to make a final investment decision in early 2012 and is making progress toward securing Asian buyers to backstop the proposed liquefied natural gas (LNG) export facility, says an Encana Corporation official.

"We are participating in the negotiations of potential off-take agreements. The discussions are based on volumes associated with the two-train facility," said Encana's vice-president of Canadian marketing, Dave Thorn. "There's been very strong interest to-date."

The facility has a proposed export capacity of 1.4 billion cubic feet per day comprised of two 700-million-cubic-foot-per-day phases. Long-term contract prices for LNG in the Asia-Pacific region typically are priced off of the Japan Customs Cleared Index used for long-term crude pricing.

Thorn said the project proponents—operator Apache Corporation has a 40 per cent stake, while Encana and EOG Resources, Inc. both have a 30 per cent share—have received expressions of interest from up to six potential LNG buyers and that deals are expected to be completed by the first quarter of 2012.

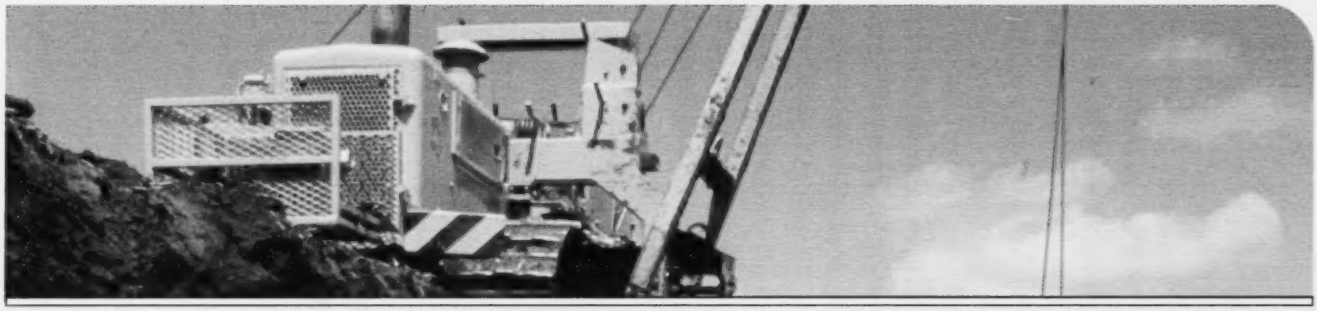
"The expressions of interest range from simply LNG supply to existing or planned re-gasification facilities, through to participation all along the value chain including shipping, equity interest in the Kitimat facility as well as upstream participation," Thorn said.

"We expect to have contracts for a significant portion of Kitimat capacity in place to support the final investment decision, expected in early 2012."

He added that a front-end engineering and design study for the Kitimat project is nearing completion and if the final investment decision is to go forward, "we expect to ramp up construction" in 2012, while first exports would be expected to begin in 2015.

"For Encana, one of the benefits we see this project providing is the opportunity to convert a portion of our natural gas pricing to crude oil-linked pricing," Thorn said.

"The Kitimat project may be sourced from any of our British Columbia or Alberta natural gas resource plays and we



expect it to contribute to an overall increase in natural gas prices to a more sustainable level."

Thorn added that the Kitimat partners also plan to have completed the construction of the $1-billion Pacific Trail Pipelines project—a 463-kilometre line that will have a capacity of one billion cubic feet per day—which will link the proposed LNG terminal to Spectra Energy Corp.'s gas processing complex in Summit Lake, B.C.

HORIZONTAL WELL PERMITTING CONTINUES TO SOAR

With Alberta activity leading the way, producers across Canada licensed 1,552 wells in September, bringing the nine-month tally to 13,440 permits, up 16 per cent from last year.

The 13,440 permits for January-September include 6,973 horizontal wells, a record to the end of the third quarter. In fact, at the year's three-quarter mark, operators have licensed more horizontal holes than the year-end horizontal permit total for 2010 (6,668).

For September, JuneWarren-Nickle's Energy Group records show 904 licences granted in Alberta, 437 approved in Saskatchewan and 69 issued in Manitoba. British Columbia assigned 138 new licences during the month (76 were approved, or input).

The year-to-date permit count rose about eight per cent in Alberta to 8,093, up from 7,481 last year, while Saskatchewan's licence count for January-September rose almost 36 per cent to 3,922 well authorizations from 2,890 in the comparable period a year ago.

To the end of September, records show 8,820 permits were approved in western Canada to drill for oil or bitumen, a high over the last 10 years, and up 46 per cent from 6,041 licences last year. Gas permitting over the first nine months of 2011 totalled 2,531 wells—a decade low—and was off 31 per cent from 3,686 permits last year. In 2005, 14,837 gas wells were licensed to the end of September.

This year's permit count also includes 1,113 oil sands evaluation wells, up from 885 permits issued to the end of September last year.

Excluding experimental wells, Canadian Natural Resources Limited led producers by licensing 128 wells in September, including 81 bitumen wells. Second-place Husky Energy Inc. permitted 106 wells, including 73 oil wells.

Crescent Point Energy Corp. and Penn West Exploration each licensed 67 wells in September.

At the three-quarter mark of the year, Canadian Natural was the only operator to crack the 1,000-permit mark. It licensed 1,181 wells (excluding experimental wells) during the January-September period, followed by Husky (897), Encana Corporation (659), Cenovus Energy Inc. (466) and Penn West (370).

Encana licensed 220 gas wells and 257 coalbed methane wells through the first nine months of the year.

PEMBINA PIPELINE PLANS $200 MILLION LIQUIDS EXTRACTION, PIPELINES PROJECT

Pembina Pipeline Corporation plans to construct, own and operate a 200-million-cubic-foot-per-day enhanced natural gas liquids (NGLs) extraction facility and associated NGLs and gas gathering pipelines in the Berland area of west-central Alberta.

The Saturn facility will be connected to Talisman Energy Inc.'s Wild River and Bigstone gas plants through existing and newly constructed gas gathering lines. Once operational, Pembina expects the facility will be able to extract up to 13,500 barrels per day of liquids.

Pembina plans to construct an 83-kilometre, eight-inch NGLs pipeline to transport the extracted NGLs from the Saturn facility to its Peace Pipeline, which delivers product into Edmonton.

Pembina expects the Saturn facility, associated NGLs and gas gathering pipelines and storage to cost approximately $200 million.

Subject to regulatory and environmental approval, Pembina expects the facility and associated pipelines to be in-service in the fourth quarter of 2013. Pembina has entered into a long-term, firm service agreement with Talisman.

"The Saturn facility is an exciting gas services and infrastructure project located in an area of strong liquids-rich natural gas supply growth," said Bob Michaleski, Pembina's president and chief executive officer. The project is consistent with the company's strategy to optimize its existing asset base and will generate additional value through integration with its conventional pipelines and midstream and marketing services, he added.

The Saturn facility, combined with Pembina's Musreau deep-cut facility and its recently announced Resthaven facility, are expected to bring Pembina's total enhanced NGLs extraction capacity to approximately 600 million cubic feet per day. This could add up to approximately 40,000 barrels per day of NGLs for transportation on Pembina's conventional pipelines by the end of 2013.

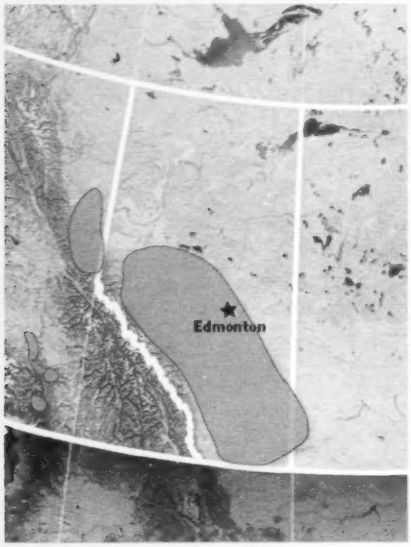
To accommodate this expected volume increase, Pembina is currently assessing its mainline capacity to determine potential expansion requirements. ■

Facts & Figures

Recent information and statistics on the natural gas industry

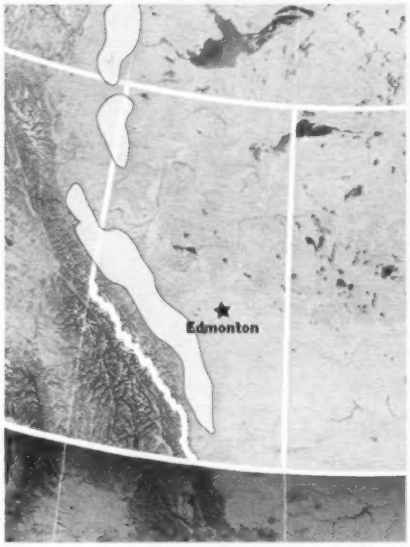
As of December 2011

COALBED METHANE



SHALE GAS

TIGHT GAS



COALBED METHANE (CBM):

The Alberta Geological Survey estimates there may be up to 500 trillion cubic feet of natural gas in Alberta's coals. It is not known how much of this gas may be economic to produce. As more information becomes available, the production potential will become clearer.

Approximately 95 per cent of the coalbed methane wells drilled in Alberta have targeted the thinner coal seams in the Horseshoe Canyon (gas in place 71 trillion cubic feet) and Belly River coal zones along the Calgary-Red Deer corridor. Wells targeting these seams tend to produce gas with little or no water. The depth range of these coals is 200-800 metres.

Most of the remaining CBM wells drilled have targeted the deeper Mannville coals (gas in place 239 trillion cubic feet). These coals tend to be thicker, deeper and more continuous with substantial saline (salt) water production. The depth range of these coals is 900-1,500 metres.

Despite depressed natural gas prices over the past few years, Encana Corporation, Quicksilver Resources Inc. and other companies are still drilling CBM wells. Encana's second-quarter 2011 CBM production was 476 million cubic feet equivalent per day, which was 12 per cent higher than the second quarter of 2010 as a result of successful drilling, acquisitions and third-party production. The company drilled 320 net wells and brought 538 new wells on stream. For 2011, it plans to drill 450 net wells.

Encana also reports it is doing more pad drilling this year to allay land disturbance concerns in more populated rural operating areas, but also to reduce its supply cost on this resource play to around $3 per thousand cubic feet.

The top producers from the Horseshoe Canyon coals are Encana, Quicksilver, Nexen Inc., and Apache Canada Ltd. Nexen and Trident Exploration are the leaders in the Mannville coals.

According to an Energy Resources Conservation Board's (ERCB) 2010 summary of reserves and production, CBM contributed 261 million cubic feet and "activity in CBM has increased from a few test wells in 2001 to more than 16,000 producing connections [wells] in 2010."

Currently, 86 per cent of producing CBM wells are in the Horseshoe Canyon. In 2010, CBM contributed eight per cent of Alberta's total marketable gas production, which the ERCB projects will increase to 13 per cent by 2020.

SHALE GAS:

Shale gas exploration and development in the Western Canadian Sedimentary Basin has undoubtedly been accelerated by the continued success of several prolific U.S. shale basins.

The potential for Canadian shale gas production is still being evaluated. In northeastern British Columbia, the most advanced shale gas plays are found in the Horn River Basin, and to a lesser extent in the Cordova Embayment. A number of companies exploring in these regions have advanced their exploration efforts to a point where pilot projects with multiple wells have been completed and natural gas is being produced

and sold via the Spectra pipeline system. Large-scale commercial development will be dependent on market conditions.

According to the ERCB, shale gas exploration and production is in its infancy in Alberta, so currently there is limited data to estimate the shale gas resource potential in the province. Knowledge obtained from American projects indicates that shale gas has the potential to add substantially to Alberta's resource and reserve base. The ERCB is currently evaluating the shale gas resource potential of all prospective shale gas formations in Alberta.

Current exploration and production is constrained by poor market conditions, but two new emerging plays in Alberta are the deep Duvernay Formation and Colorado Group shales located in the western part of the province. Limited testing has taken place with encouraging results, but no commercial projects have been developed to date.

TIGHT GAS:

The Western Canadian Sedimentary Basin is host to most of Canada's conventional natural gas resources and within this basin, the northern and western regions contain much of the tight gas potential.

Total original gas in place (OGIP) is estimated at 1,311 trillion cubic feet. Other regions within Canada, specifically the Mackenzie Delta in the Arctic and the Albert Formation in the Maritimes, are believed to have tight gas resource potential, but no estimates have been made due to lack of geological data.

While the OGIP value is very large, only a portion of these resources are deemed technologically recoverable. Marketable resources are estimated at between 230 and 509 trillion cubic feet, with half attributed to the Deep Basin and the Montney in Alberta, and the rest to various accumulations in northeastern British Columbia.

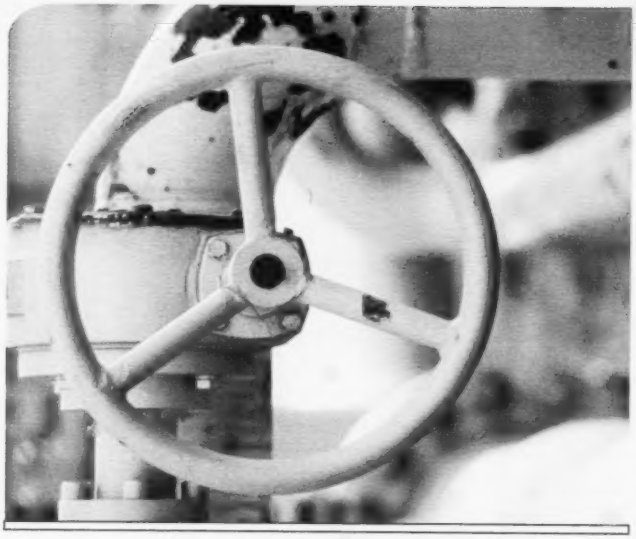
NATURAL GAS LIQUIDS (NGLs):

Natural gas liquids (NGLs) are recovered mainly from the processing of natural gas in Alberta. Field gas-processing facilities ensure that natural gas meets the quality specifications of the rate-regulated natural gas pipeline systems, which require removal of NGLs to meet pipeline hydrocarbon dew point specifications. Field plants may send recovered NGL mix to centralized, large-scale fractionation plants where the mix is fractionated in specification products. Gas reprocessing plants, often referred to as straddle plants, recover NGL components or NGL mix from marketable gas and are usually located on the main gas transmission pipelines at border delivery points.

In Alberta, there are about 550 active gas processing plants that recover NGL mix or specification products, 10 processing plants that fractionate NGL mix streams into specification products and nine straddle plants.

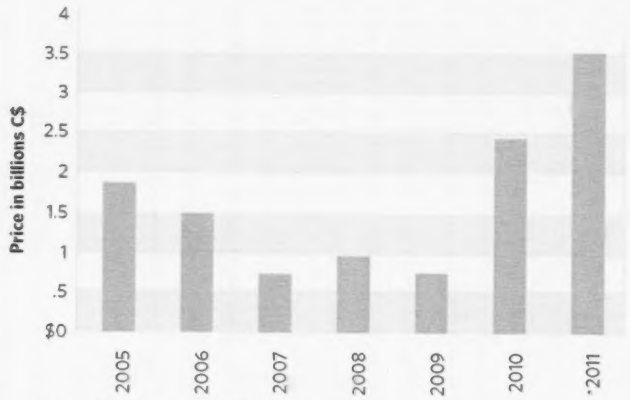
Remaining established reserves of extractable ethane is estimated to be 113 million cubic metres (716 million barrels). The remaining established reserves of other NGLs—propane, butane and pentanes plus—is 148 million cubic metres (932 million barrels).

All of the specification ethane extracted from natural gas was used in Alberta as feedstock. The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas, with four plants using ethane as feedstock for the production of ethylene. The petrochemical industry in Alberta is benefiting from the low gas price environment since the price of ethane is linked to natural gas prices. The Alberta ethylene industry continues to maintain its historical cost-advantage for ethylene production compared to other regions in North America. ■



ALBERTA CROWN LAND SALES

P&NG rights, excluding oil sands



*Numbers for 2011 include sales up to December 14.

Source: Alberta Energy

DRILLING RIG COUNT BY PROVINCE/TERRITORY

Western Canada Dec. 6, 2011

	ACTIVE	DOWN	TOTAL	ACTIVE
Western Canada				(Per cent of total)
Alberta	363	198	**561**	65%
British Columbia	55	24	**79**	70%
Manitoba	24	3	**27**	89%
Saskatchewan	93	38	**131**	71%
WC Total	**535**	**263**	**798**	**67%**
Northwest Territories	0	0	**0**	0%

Source: Canadian Association of Energy Contractors

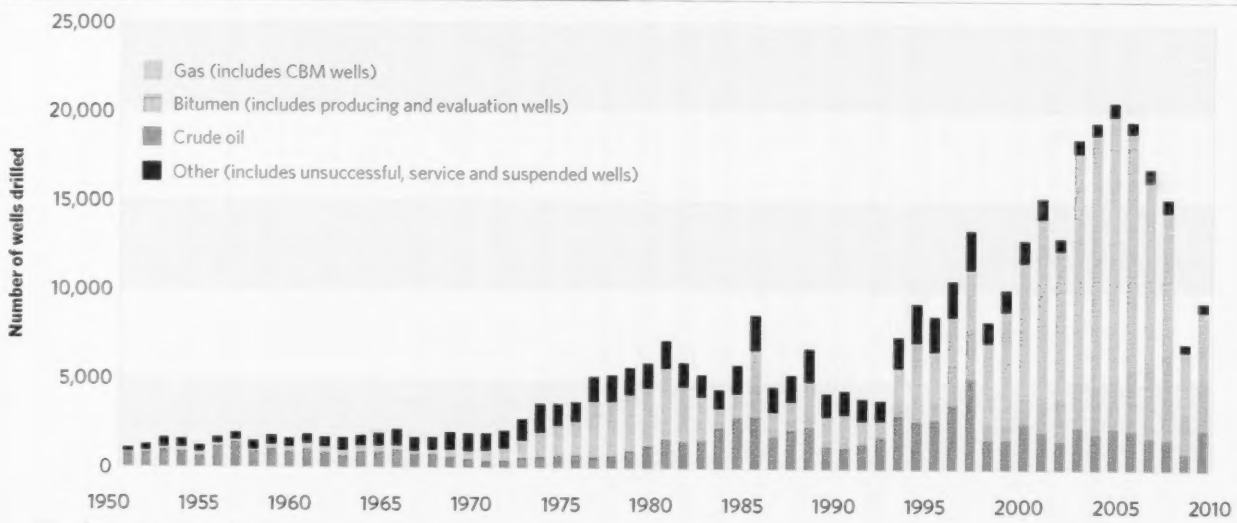
OIL & GAS WELL COMPLETIONS BY PROVINCE/TERRITORY

Western Canada November 2011

	OIL WELLS		GAS WELLS	
Western Canada	**November 2011**	**November 2010**	**November 2011**	**November 2010**
Alberta	559	591	242	842
British Columbia	6	3	86	140
Manitoba	103	70	-	-
Saskatchewan	525	217	4	3
Total	**1,193**	**881**	**332**	**985**
Northwest Territories	0	0	0	0%

Source: Canadian Association of Energy Contractors

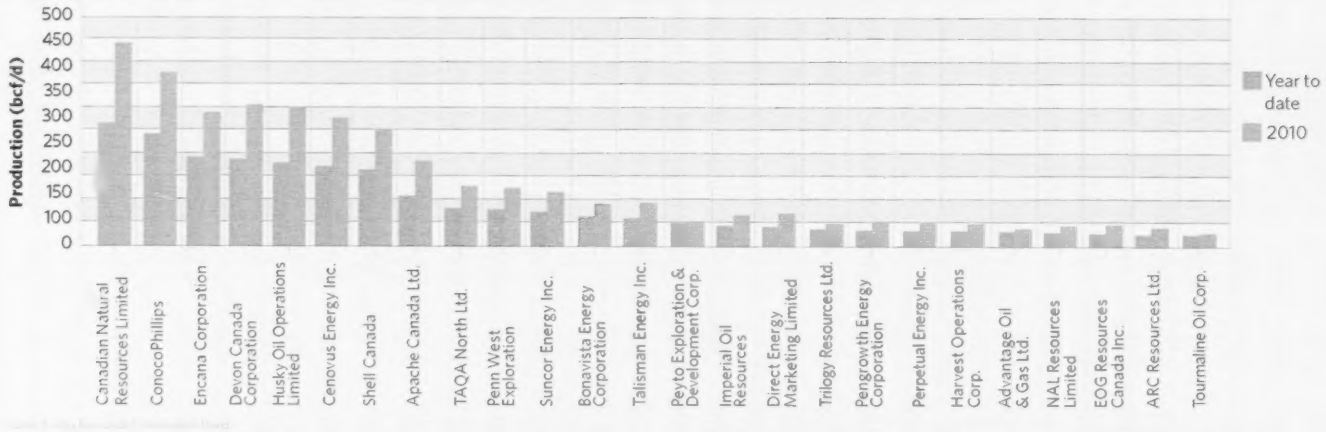
DRILLING ACTIVITY IN ALBERTA, 1950–2010



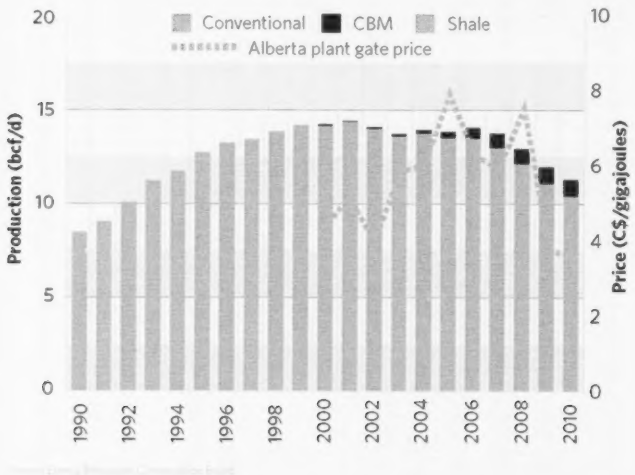
Source: Alberta Energy

Top 25 Gas Producers in Alberta (as of Oct. 6, 2011)

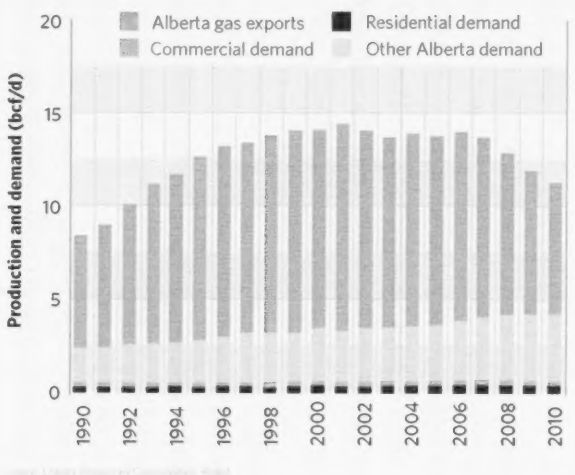
Only gas production reported from oil and gas batteries, gas gathering systems and gas plants is considered. Bitumen facilities, straddle plants and fractionation plants are excluded, as is gas from commercial gas storage schemes.



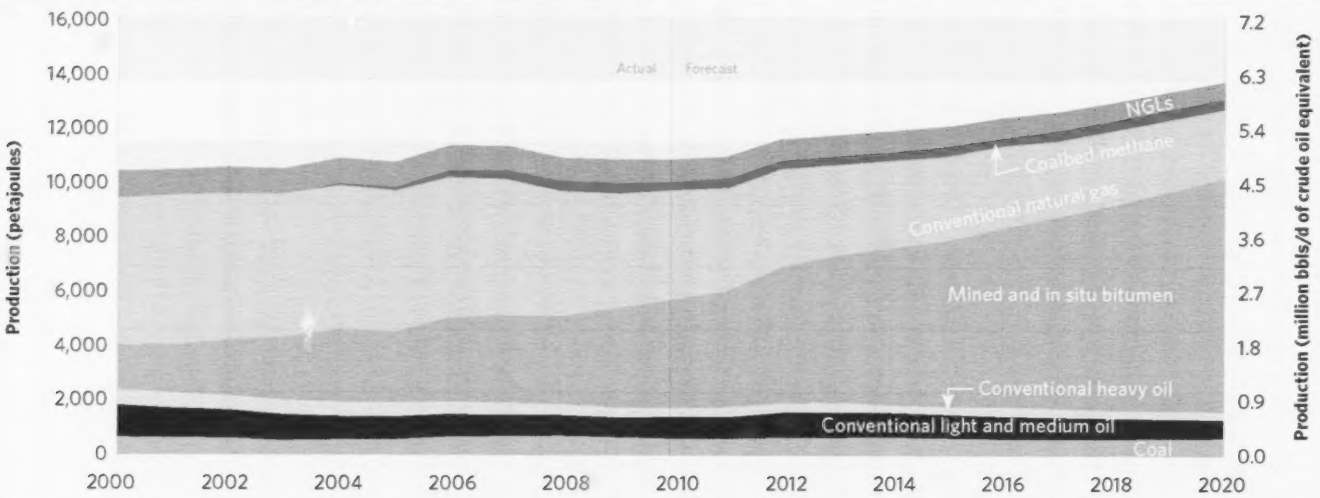
ALBERTA MARKETABLE GAS PRODUCTION



ALBERTA MARKETABLE GAS DEMAND



TOTAL PRIMARY ENERGY PRODUCTION IN ALBERTA



Glossary of natural gas terms

Abandoned well:
A well that is permanently shut down because it was a dry hole or because it has ceased to produce crude oil or natural gas.

Acid gas:
Hydrogen sulphide (H_2S) or carbon dioxide (CO_2) or a combination of H_2S and CO_2, which are referred to as acid gases because they form acids or acidic solutions in the presence of water.

Audits:
Actions taken by staff or a third party to help measure a company's compliance with legislation and internal requirements, and to identify opportunities for improvement. Audits can involve field inspections, interviews with management and document review.

Blowout preventer (BOP):
Equipment that is installed at the wellhead to control pressures and fluids and to prevent uncontrolled fluid flow from the reservoir during drilling, completion and certain remedial operations to restore production.

Broker:
An individual or independent corporation engaged in bringing together sellers and buyers of natural gas, assisting in negotiations, and arranging transportation and delivery terms. Brokers usually do not buy or sell for their own account but act as an agent for the buyer and/or seller.

Burner-tip:
The point of end-use consumption of a particular fuel, such as natural gas or residual fuel oil.

Burner-tip price:
The price of natural gas (or other fuels) paid by the final consumer. For natural gas, this includes the price of the gas plus the cost of processing, gathering, transmitting and distributing it.

Butane (C_4H_{10}):
A natural gas liquid (NGL) used as a household fuel, refrigerant and aerosol propellant and in the manufacture of synthetic rubber.

Caprock:
Impermeable rocks such as shale that overlie the reservoir rock and trap natural gas and crude oil in the reservoir. Also, impermeable rock overlying a geothermal reservoir. Also called sealing rock.

Carbon dioxide (CO_2):
A non-toxic gas produced from decaying materials, respiration of plant and animal life, and combustion of organic matter, including fossil fuels; carbon dioxide is the most common greenhouse gas produced by human activities.

Carbon monoxide (CO):
Colourless, odourless, poisonous gas produced by incomplete combustion of fossil fuels.

Coalbed methane:
Natural gas generated during the coalification process and trapped within coal seams, commonly referred to as natural gas from coal.

Commingled gas:
A homogeneous mix of natural gas from various physical (or contractual) sources.

Completion:
Preparing a newly drilled well for production; usually involves setting casing—pipe that lines the interior of a well to prevent caving and protect against groundwater contamination—and perforating the casing to establish communication with the producing formation.

Compressed natural gas (CNG):
Natural gas in its gaseous state that has been compressed to about one per cent of its volume and stored at 20,000–27,500 kilopascals.

Condensate:
A mixture of hydrocarbons consisting primarily of pentanes and heavier liquids extracted from natural gas. While it can be used to make gasoline, jet fuel and other products, it is primarily used in Alberta as diluent.

Conventional gas:
Natural gas that can be produced using recovery techniques normally employed by the oil and gas industry. The distinction between conventional and unconventional gas is becoming less clear. See also *unconventional gas*.

Deep cut:
The processes that recover NGLs from natural gas in excess of amounts required for sales gas to meet pipeline specifications.

Deliverability:
The amount of natural gas a well, field, gathering, transmission or distribution system can supply in a given period of time.

Directional drilling:
Drilling a wellbore at any angle other than vertical; used where the rig cannot be set up directly over the target, or to drill more than one hole from a single location.

Downstream:
The refining and marketing sector of the petroleum industry.

Dry gas:
Natural gas from the well that is free of liquid hydrocarbons, or gas that has been treated to remove all liquids; pipeline gas.

Energy Resources Conservation Board (ERCB):
An independent, quasi-judicial agency of the Government of Alberta. Its mission is to ensure that the discovery, development and delivery of Alberta's energy resources take place in a manner that is fair, responsible and in the public interest.

Established reserves:
Generally defined as proved reserves, plus one half probable reserves.

Ethane (C_2H_6):
An NGL, the uses of which include enhanced oil recovery, as a fuel and as a feedstock for the petrochemical industry.

Flaring:
Controlled burning of natural gas that cannot be processed for sale because of technical or economic reasons. The biggest portion is solution gas flaring, which involves the burning of natural gas produced along with crude oil and bitumen.

Fracturing (or fracking):
A reservoir stimulation technique in which fluids are pumped into a potentially productive formation under high pressure to create or enlarge fractures allowing the oil or gas to flow from the zone at higher rates. In some operations, proppants such as frac sand are injected with the frac fluid to help hold the rock fractures open.

Gas:
One of the three states of matter; gas is characterized by having neither shape nor specific volume; it expands to fill the entire container in which it is held.

Gas processing plant:
Any facility that performs one or more of the following: removing liquefiable hydrocarbons from wet gas or casinghead gas; removing undesirable gaseous and particulate elements from natural gas; removing water or moisture from the gas stream.

Gas reservoir:
A porous and permeable rock formation in which natural gas accumulates.

Gas transmission systems:
Pipelines that carry natural gas at high pressure from producing areas to consuming areas.

Gathering system:
A system of small-diameter plastic or steel pipes (gathering lines) transporting natural gas from producing wells to field facilities.

Horizontal drilling:
Drilling horizontally through a reservoir to increase the exposure of the formation to the well.

Hydrocarbons:
A large class of liquid, solid or gaseous organic compounds, containing only carbon and hydrogen, which are the basis of almost all petroleum products.

Hydrogen sulphide (H_2S):
A naturally occurring, highly toxic gas with the odour of rotten eggs.

Inert gases:
Gases that are unable to or unlikely to react with any other substance.

Injection (oil and gas):
Injection enhancement technique wherein water or other substances are injected into an oilfield to improve production. Also, the re-injection of natural gas into an oilfield to maintain reservoir pressure.

Inlet separation:
The initial stage of processing at a natural gas processing plant where the incoming raw gas stream enters a vessel and any free liquids, such as water and NGLs, are removed from the gas stream before it is further processed.

Land:
In the petroleum industry, "land" often refers to the oil and gas rights on a particular area of land. For example, in a "land sale," the oil and/or gas rights are "sold" (although in reality the rights are leased).

Landman:
A male or female member of the exploration team whose primary duties are managing a petroleum company's relations with its landowners and partners, including securing and administering oil and gas leases and other agreements. Other duties include helping to formulate exploration and development strategies. Also known as a land agent or land person.

Lease agreement:
The negotiated legal document giving an oil and gas company the right to utilize the surface lease site to drill for and produce oil or gas.

Liquefied natural gas (LNG):
Supercooled natural gas that is maintained as a liquid at or below -160°C; LNG occupies 1/640th of its original volume and is therefore easier to transport if pipelines cannot be used.

Manufactured gas:
A gas obtained by destructive distillation of coal, by the thermal decomposition of oil or by the reaction of steam passing through a bed of heated coal or coke. Examples are coal gases, coke or oven gases, producer gas, blast furnace gas, blue (water) gas or carbureted water gas (also known as syngas).

Methane (CH_4):
Methane consists of one carbon atom and four hydrogen atoms and is the largest component of natural gas. Methane remains in a gaseous state at relatively low temperatures and pressures. Methane is also produced when organic matter decomposes.

Midstream sector:
Primarily the processing, storage and transportation sector of the energy industry.

Mineral rights:
The rights to explore for and produce the resources below the surface. In the petroleum industry, mineral rights can also be referred to as "land."

National Energy Board (NEB):
The federal regulatory agency in Canada that authorizes oil, natural gas and electricity exports; certifies interprovincial and international pipelines, and designated interprovincial and international power lines; and sets tolls and tariffs for oil and gas pipelines under federal jurisdiction.

Natural gas:
Gaseous petroleum consisting primarily of methane with lesser amounts of (in order of abundance) ethane, propane, butane and pentane, and heavier hydrocarbons as well as non-energy components such as nitrogen, carbon dioxide, hydrogen sulphide and water.

Natural gas liquids (NGLs):
Liquids obtained during production of natural gas, comprising ethane, propane, butane and condensate.

Non-associated gas:
Natural gas that is produced from reservoirs that contain only natural gas, and is therefore not associated with crude oil production.

Operator:
The company responsible for managing an exploration, development or production operation.

Orphan wells:
Wellsites for which the licence operators have ceased to exist or cannot be traced.

Pentane (C_5H_{12}):
A hydrocarbon compound consisting of five carbon atoms and 12 hydrogen atoms.

Petroleum:
A naturally occurring mixture composed predominantly of hydrocarbons in the gaseous or liquid phase.

Probable reserves:
Reserves believed to exist with reasonable certainty based on geological information.

Propane (C_3H_8):
An NGL used as a fuel (i.e.: in barbeques, transportation and heating of households in areas where natural gas supply is not available).

Proppant:
Sand, or ceramic or resin beads pumped into a wellbore at the end of the fracturing process to prop open newly induced fractures and enhance permeability.

Proved reserves:
Reserves that can be economically produced with a large degree of certainty from known reservoirs using existing technology.

Raw natural gas:
A mixture containing methane plus all or some of the following: ethane, propane, butane, condensates, nitrogen, carbon dioxide, hydrogen sulphide, helium, hydrogen, water vapour and minor impurities. Raw natural gas is the gas found naturally in the reservoir prior to processing.

Recoverable resources:
Hydrocarbon reserves that can be produced with current technology, including those not economical to produce at present.

Renewable energy:
Naturally occurring energy sources that are continually replenished. Examples of renewable energy are wind, solar and water.

Reserves:
Recoverable portion of resources available for use based on current knowledge, technology and economics.

Reservoir (oil and gas):
A porous and permeable underground rock formation containing a natural accumulation of crude oil or natural gas that is confined by impermeable rock or water barriers, and is separate from other reservoirs.

Sales gas:
Natural gas that has been treated in a natural gas processing facility and is suitable for sale. Some of the processes that natural gas may undergo are inlet separation, gas treating, dehydration and NGL recovery, before it enters a transmission pipeline for eventual transportation to market.

Shale gas:
Natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas.

Solution gas:
Natural gas that is dissolved in crude oil in underground reservoirs. When the oil comes to the surface, the gas expands and comes out of the oil.

Sour gas:
Raw natural gas with a relatively high concentration of sulphur compounds, such as hydrogen sulphide. All natural gas containing more than one per cent hydrogen sulphide is considered sour. About 30 per cent of Canada's natural gas production is sour, most of it found in Alberta and northeastern British Columbia.

Source rock:
The rocks in which hydrocarbons are created or sourced from carbohydrates through heat and pressure. Source rocks are often black shales.

Straddle extraction plant:
A gas processing plant located on or near a gas transmission line that removes natural gas liquids from the gas and returns it to the line.

Sulphur recovery:
Sour gas is processed at recovery plants to extract sulphur for sale to fertilizer manufacturers and other industries in Canada and overseas. The average rate of sulphur recovery at Alberta's sulphur recovery plants has improved from 97.5 per cent in 1980 to 98.8 per cent in 2000.

Sweet gas:
Raw natural gas with a relatively low concentration of sulphur compounds, such as hydrogen sulphide.

Syngas:
A fuel produced from solid hydrocarbons such as coal and petroleum coke. The process uses steam, air and controlled amounts of oxygen to break the solid down, and the resulting gas consists of vaying amounts of carbon monoxide and hydrogen.

Tight gas sands:
Natural gas that is found in sandstone with low permeability.

Trunk lines:
Large-diameter pipelines that transport crude oil, natural gas liquids and refined petroleum products to refineries and petrochemical plants; some trunk lines also transport refined products to consuming areas.

Unconventional natural gas:
In the case of natural gas from coal, natural gas from tight sands and shale gas, conventional gas found in unconventional reservoirs or reservoirs requiring special production methods or technologies; in the case of gas hydrates, conventional methane in an unconventional form occurring in a conventional reservoir.

Upstream:
Refers to companies that explore for, develop and produce petroleum resources (in contrast, downstream refers to the refining and marketing components of the industry).

Western Canadian Sedimentary Basin (WCSB):
Canada's largest region of sedimentary rocks; the largest source of current oil and gas production, covering all of Alberta and parts of Manitoba, Saskatchewan, British Columbia and the Yukon.

Wet gas:
Raw natural gas with a relatively high concentration of natural gas liquids (ethane, propane, butane and condensates).

CONTACTS

Industry Associations

• Alberta Land Surveyor's Association	**www.alsa.ab.ca**
• Canadian Association Geophysical Contractors	**www.cagc.ca**
• Canadian Association of Oilwell Drilling Contractors	**www.caodc.ca**
• Canadian Association of Petroleum Producers	**www.capp.ca**
• Canadian Energy Pipeline Association	**www.cepa.com**
• Canadian Gas Association	**www.cga.ca**
• Canadian Natural Gas	**www.canadiannaturalgas.ca**
• Canadian Natural Gas Vehicle Alliance	**www.cngva.org**
• Canadian Society of Exploration Geophysicists	**www.cseg.ca**
• Canadian Society of Petroleum Engineers	**www.speca.ca**
• Canadian Society for Unconventional Resources	**www.csur.ca**
• Gas Processing Association Canada	**www.gpacanada.com**
• Petroleum Services Association of Canada	**www.psac.ca**
• Petroleum Technology Alliance Canada	**www.ptac.org**
• Small Explorers and Producers Association of Canada	**www.sepac.ca**

Alberta Government

• Alberta Energy	**www.energy.gov.ab.ca**
• Alberta Environment and Water	**www.environment.alberta.ca**
• Alberta Sustainable Resource Development	**www.srd.alberta.ca**
• Alberta Treasury Board & Enterprise	**www.treasuryboard.alberta.ca**
• Energy Resources Conservation Board	**www.ercb.ca**
• Alberta Innovates	**www.albertainnovates.ca**
• Alberta Geological Survey	**www.ags.gov.ab.ca**
• Alberta Surface Rights Board	**www.surfacerights.gov.ab.ca**

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